BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2020-263-E

Cherokee County Cogeneration Partners, LLC Complainant/Petitioner, v. Duke Energy Progress, LLC and Duke Energy Carolinas, LLC, Defendants/Respondents.	)	**DIRECT TESTIMONY OF GLEN A. SNIDER ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glen A. Snider. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am currently employed by Duke Energy as Director of Carolinas Integrated Resource Planning and Analytics.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES IN YOUR POSITION WITH DUKE ENERGY.

A. I am responsible for the supervision of the Integrated Resource Plans ("IRPs") for both Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, the "Companies"). In addition to the production of the IRPs, I have responsibility for overseeing the analytic functions related to resource planning for the Carolinas region. Examples of such analytic functions include unit retirement analyses, the analytical support for applications for certificates of environmental compatibility and public convenience and necessity for new generation, and analyses required to support the Companies' avoided cost calculations that are used in the biennial avoided cost rate proceedings.

I have extensive experience with the federal regulatory framework implementing Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), including the Federal Energy Regulatory Commission's ("FERC") implementing regulations. I am also familiar with the history of PURPA implementation in South Carolina, including the recent PURPA implementation by the Public Service Commission of South Carolina (Commission") under the South Carolina Energy Freedom Act of 2019 ("Act 62" or the "Act"). I previously testified in the Companies' initial 2019 avoided cost proceedings to implement the PURPA provisions of Act 62 (in Docket Nos. 2019-185-E and 2019-186-E) ("2019 Avoided Cost Proceeding"). I have also been involved in numerous PURPA implementation proceedings in the Companies' North Carolina jurisdiction dating back to 2012.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. My educational background includes a Bachelor of Science in mathematics and a Bachelor of Science in economics from Illinois State University. With respect to professional experience, I have been in the utility industry for over thirty years. I started as an associate analyst with the Illinois Department of Energy and Natural Resources, responsible for assisting in the review of Illinois utilities' integrated resource plans. In 1992, I accepted a planning analyst job with Florida Power Corporation and for the past twenty years have held various management positions within the utility industry. These positions have included managing the Risk Analytics group for Progress Ventures and the Wholesale Transaction Structuring group for ArcLight Energy Marketing. Immediately prior to the merger of Duke Energy Corporation and Progress Energy, I was Manager of Resource Planning for Progress Energy Carolinas. From 2012 to present I have held the position of Director of Resource Planning and Analytics for DEC and DEP.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes. I have testified before the Commission on a number of occasions, most recently in the Commission's proceedings to review DEC's and DEP's 2020 IRPs in Docket Nos. 2019-224-E and 2019-225-E. Most recently, I have submitted pre-filed direct testimony in DEC's and DEP's 2021 avoided cost proceedings in Docket Nos. 2021-89-E and 2021-90-E.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to respond to the direct testimony of Cherokee County Cogeneration, LLC ("Cherokee") Witness Kurt Strunk. I provide an overview of the avoided cost framework under PURPA and Act 62. I address the concept of a legally enforceable obligation, or "LEO," and how that concept applies in this case. I discuss the Companies' methodology and procedure for determining avoided cost rates under the applicable laws and Commission precedent and explain when DEC's and DEP's first year of capacity need arose under the relevant IRPs. I also discuss the reasons why avoided costs have declined since Cherokee entered into its 2012 power purchase agreement ("PPA") with DEC. Finally, I provide an overview of the transparency requirements to which the Companies were obligated to adhere in the course of their dealings with Cherokee.

Q. WERE YOU PERSONALLY INVOLVED IN THE DISCUSSIONS WITH CHEROKEE IN 2018-2020?

A. I was not. My testimony focuses on the avoided cost framework under PURPA and Cherokee's allegations regarding the establishment of LEOs with DEC and DEP. I have been directly involved in numerous avoided cost and other proceedings that addressed LEOs and, most importantly, I was directly involved in the Companies' 2019 Avoided Cost Proceedings where the Commission addressed LEO requirements in South Carolina.

II. OVERVIEW OF PURPA AND ACT 62 AVOIDED COST FRAMEWORK

Q. PLEASE EXPOUND ON PURPA'S PRINCIPLE OF CUSTOMER INDIFFERENCE AND NONDISCRIMINATION IN SETTING AVOIDED COST RATES FOR PURCHASES FROM QFs.

A. While I am not an attorney, I have become familiar with Section 210 of PURPA and FERC's regulations implementing PURPA through my role at the Companies. Section 210 of PURPA rests on the twin pillars of nondiscrimination and customer indifference. Specifically, Section 210 of PURPA requires that the price paid by utilities for "must take" purchases of QF output be "just and reasonable to the electric consumers of the electric utility and in the public interest, and shall not discriminate against qualifying cogenerators or qualifying small power producers."[1] FERC has confirmed the need to ensure customer indifference to utility purchases of QF power, stating that, in enacting PURPA, "[t]he intention [of Congress] was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives."[2]

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[1] 16 U.S.C. § 824a–3(b).

[2] *Southern Cal. Edison Co., et al.*, 71 FERC ¶ 61,269, at 62,080 (1995), *overruled on other grounds, Cal. Pub. Util. Comm'n*, 133 FERC ¶ 61,059 (2010).

PURPA limits the rates to be paid to QFs to the purchasing utility's incremental or "avoided" cost, which is designed to ensure customers remain indifferent between the costs of utility or non-utility generation and, thereby, prohibits unjustly subsidizing QFs by paying rates that exceed avoided costs.[3] Said another way, the "must purchase" obligation under PURPA requires utilities to offer to purchase QF power at "just and reasonable" rates that result in customer indifference as to whether the energy purchased is generated by the utility's generating fleet or purchased from the QF's generating facility pursuant to PURPA. Overall, these twin pillars promote fairness in the marketplace toward both QFs and the Companies' customers.

Q. DOES THE DEFINITION OF AVOIDED COST IN ACT 62 ALIGN WITH THE GENERAL REQUIREMENTS OF PURPA?

A. Yes, Act 62 defines "avoided cost" as:

> . . . the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.[4]

This is precisely the same definition prescribed by the FERC's implementing regulations.[5] Act 62's definition of avoided cost reflects PURPA's foundational requirement that purchasing QF power at the utility's avoided cost, if accurately

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[3] 16 U.S.C.§ 824a-3(b); 16 U.S.C.§ 824a-3(d); 18 C.F.R. § 292.301(b); *Connecticut Light and Power Co.*, 70 FERC ¶ 61,012, at 61,023, 61,028, *reconsideration denied*, 71 FERC ¶ 61,035, at 61,151-61,153 (1995), *appeal dismissed*, 117 F.3d 1485 (D.C. Cir. 1997).
[4] S.C. Code Ann. § 58-41-10(2).

[5] 18 C.F.R. § 292.101(b)(6).

quantified, ensures customers remain indifferent between the costs of utility or non-utility generation.

Q. HAS FERC ISSUED NEW GUIDANCE ON PURPA RECENTLY?

A. Yes. On July 16, 2020, FERC issued Order No. 872[6], which updated FERC's regulations to provide state commissions tasked with implementing PURPA increased flexibility in establishing avoided cost rates for purchases of QF power. FERC revised its regulations implementing PURPA's mandatory purchase obligation "based on demonstrated changes in circumstances since the current PURPA Regulations were first adopted to ensure that the regulations continue to comply with PURPA's statutory requirements established by Congress."[7]

Q. HAVE THE COMPANIES ADHERED TO FERC'S REGULATIONS IMPLEMENTING PURPA AND THE REQUIREMENTS OF ACT 62 IN PROVIDING PURPA RATES TO CHEROKEE?

A. Yes. As I discuss further in my testimony, the Companies have adhered to the requirements I have discussed above with respect to Cherokee. This is true even though Cherokee is a cogeneration facility, and not a small power producer as that term is defined under PURPA and Act 62. DEC/DEP Witness John Freund provides additional detail regarding the calculation of the avoided cost rates provided to Cherokee, and DEC/DEP Witness Michael Keen provides additional detail regarding the negotiations between the Companies and Cherokee.

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[6] *See Qualifying Facility Rates and Requirements, Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Order No. 872, 172 FERC ¶ 61,041 (Jul. 16, 2020) ("Order No. 872"), *affirmed and clarified by* Order No. 872-A, 173 FERC ¶ 61,158 (Nov. 19, 2020).

[7] Order No. 872 at P 20.

III. LEGALLY ENFORCEABLE OBLIGATION

Q. CAN YOU EXPLAIN WHAT A LEO IS AND HOW IT WORKS?

A. Yes. As I noted earlier, under PURPA, a QF has the unconditional right to choose whether to sell its power "as available" or pursuant to a "legally enforceable obligation" or "LEO" at a forecasted avoided cost rate determined, at the QF's option, either at the time of delivery or at the time the obligation is incurred.[8] While I am not an attorney, and Witness Kendal Bowman speaks to this issue in greater detail, it is my general understanding that the LEO concept was intended "to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility."[9] FERC has explained that the concept of a LEO recognizes that a QF may commit to sell its electric output through execution of a contract or, "if the electric utility refuses to sign a contract, the QF may seek state regulatory authority assistance to enforce the PURPA-imposed obligation on the electric utility to purchase from the QF, and a non-contractual, but still legally enforceable, obligation will be created pursuant to the state's implementation of PURPA."[10] Thus, the unique non-contractual LEO concept created in FERC's regulations is intended to protect the QF's right to sell power to the utility under PURPA where the QF and the utility cannot agree to a form of PPA, the specified term of PPA, or

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[8] *See* 18 C.F.R. § 292.304(d).

[9] *Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, 45 Fed. Reg. 12,214, at 12,224 (Feb. 25, 1980) ("Order No. 69").

[10] *Grouse Creek Wind Park, LLC*, 142 FERC ¶ 61,187 at P 40 (2013) (*citing JD Wind 1, LLC*, 129 FERC ¶ 61,148 at P 25 (2009) ("*JD Wind 1*")).

some other aspect of the contractual relationship between the QF and the utility.

Put simply, FERC's LEO concept set forth in 18 C.F.R. § 292.304(d)(2) provides that the QF and the utility can either negotiate and enter into to a PPA or, if the utility refuses to enter into a contract, the QF can still bind the utility to purchase power from the QF by establishing a non-contractual, but still binding, LEO prior to executing a PPA.

Q. HAS FERC ESTABLISHED SPECIFIC STANDARDS OR REQUIREMENTS THAT QFs MUST MEET TO ESTABLISH A NON-CONTRACTUAL LEO?

A. FERC has recently established requirements in Order No. 872 that QFs must demonstrate financial commitment and commercial viability to establish a non-contractual LEO.[11] Witness Bowman addresses this recent guidance in more detail. Prior to Order No. 872, FERC had provided general guidance that "a QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, *but binding, legally enforceable obligations*."[12] FERC has also made clear that "the establishment of a legally enforceable obligation turns on the QF's commitment, and *not* the utility's actions."[13]

It is my understanding that PURPA and FERC provide state commissions with wide latitude to define when and how a LEO is created—either on a case-by-

[11] Order No. 872 at P 684; 18 C.F.R. § 292.304(d)(3).

[12] *JD Wind 1*, 129 FERC ¶ 61,148 at P 25 (emphasis added).

[13] *FLS Energy, Inc.*, 157 FERC ¶ 61,211 at P 24 (2016) (emphasis in original).

case basis or by establishing a general rule or standard—so long as the state's LEO requirements are not otherwise inconsistent with FERC's regulations.

Q. FROM YOUR PERSPECTIVE AS THE DIRECTOR OF INTEGRATED RESOURCE PLANNING, WHY IS IT NECESSARY FOR A QF TO MAKE A MEANINGFUL AND BINDING COMMITMENT TO SELL AND DELIVER POWER TO THE COMPANIES TO ESTABLISH A LEO?

A. Once a PURPA PPA expires, a QF is no longer contractually bound to sell to a utility and is free to make any number of business decisions without liability or accountability to the previously-purchasing utility. For example, the QF can elect not to enter into a new fixed price contract and sell energy "as-available" under PURPA, or the QF can sell its power to another buyer in the wholesale market on a non-PURPA basis, or the QF can elect to shut down its facility and cease selling power altogether. From a resource planning perspective, the utility cannot rely upon the QF to deliver capacity and energy over a future term to serve customers unless and until the QF signs a new PPA committing itself to do so. In Order No. 872, FERC recognized the importance of "allow[ing] utilities to reasonably rely on the LEO in planning for system resource adequacy."[14] FERC indicated that a QF must make a sufficient demonstration of a commitment to sell "such that it is reasonable for a utility to consider the resource in its planning projections."[15] To me, this means that one of the purposes of the LEO is to memorialize the QF's commitment to sell to the utility at the utility's avoided costs, so that the utility can

[14] Order No. 872 at P 687.
[15] *Id*. at P 694.

then rely on the QF's capacity and energy to serve its customers.

Q. HOW DOES A QF ESTABLISH A LEO WITH DEC OR DEP IN SOUTH CAROLINA?

A. Pursuant to Act 62, small power producers may establish a LEO by submitting to the utility the Notice of Commitment ("NOC") Form required by Section 58-41-20(D) of Act 62 and approved by the Commission in the 2019 Avoided Cost Proceeding. By delivering a NOC Form, the Act prescribes that the QF is committing to sell its output (a) at the avoided cost rates, and (b) pursuant to the PPA terms in effect at the time it submits the form to the utility.[16] The Commission approved the first NOC Form in the 2019 Avoided Cost Proceeding.[17]

Q. PLEASE DESCRIBE THE CONTRACTING PROCESS FOR LARGE QFs SELLING UNDER PURPA IN SOUTH CAROLINA AT THE TIME WHEN CHEROKEE AND THE COMPANIES BEGAN NEGOTIATING FOR A NEW PPA.

A. For QFs larger than 2 MW not eligible for the Commission-approved standard rates and terms, such as Cherokee, the Companies followed a standardized process for negotiating a PPA with a QF that used a consistent methodology to update avoided costs monthly. The process begins at the QF's election by submitting project specific information to the utility along with a request for avoided cost pricing. The QF has the right to request the applicable utility to tender to the QF current avoided

[16] *See* S.C. Code Ann. § 58-41-20(D).

[17] Order No. 2019-881(A) at 139-153, Docket Nos. 2019-185-E and 2019-186-E (Jan. 2, 2020) ("Order No. 2019-881(A)").

cost pricing and an executable purchase power agreement or "PPA" at any time. If requested by the QF, DEC or DEP (as applicable) would submit avoided cost pricing and work toward an associated PPA. The avoided cost pricing that is tendered to the QF remains valid for a reasonable period of time to allow the QF and the utility to work to finalize the PPA (normally 60 days). If the QF elects not to proceed with finalizing the PPA for execution, the QF may request new pricing in the future. If agreement cannot be reached on specific terms of the PPA, the QF or the utility may petition the Commission for review to resolve any disputes. Once the parties are in full agreement on all terms and conditions of the PPA, the utility would prepare and forward to the QF owner a final, executable PPA, which is executed by the QF and returned to DEC or DEP.

In addition to the Companies' standard commercial terms and conditions memorializing the contractual obligations of the parties, the final executable PPA includes the QF's committed commercial operation date, as well as information regarding the QF's nameplate capacity and estimated annual deliveries of energy over the specified term of the PPA. In this manner, the PPA memorializes the QF's "legally enforceable obligation" or binding contractual commitment to commence delivering power to the utility on the commercial operation date for the specified term of the PPA. The utility can at that point also rely on the QF's capacity and energy for the future term of the contract, because the contract provides that the QF is obligated to deliver energy on and after the commercial operation date that the QF has committed to in the PPA. Once executed, failure to perform pursuant to the contract terms and conditions puts the QF at risk of default and incurring financial damages and potential termination of the PPA.

Q. IN YOUR OPINION, HOW DOES THE COMMISSION'S DETERMINATION OF WHEN A LEO OCCURS IMPACT THE COMPANIES' CUSTOMERS?

A. The date the QF establishes a LEO ordinarily "locks in" the avoided cost rates that DEC or DEP (as applicable) pays a QF. Since the Companies' customers ultimately pay the avoided cost rates that the Companies pay to QFs, it is important that the date on which the LEO is recognized is reasonably aligned with the date on which customers begin receiving (and paying for) the QF power. This has been an important focus of LEO policy as avoided cost rates have consistently declined in recent years, creating the potential for customers to pay for QF power at "stale" rates that are higher than actual avoided cost, as a result of a LEO purportedly established years before the power was ever actually delivered.

Q. WHEN DOES CHEROKEE CLAIM TO HAVE ESTABLISHED LEOs WITH DEC AND DEP?

A. Cherokee claims that it established a LEO with DEC on September 17, 2018, by submitting a letter and a NOC Form to Witness Keen, and that it established a LEO with DEP on December 12, 2018 by doing the same.

Q. DO YOU AGREE THAT CHEROKEE ESTABLISHED LEOs WITH DEC AND DEP ON THESE DATES?

A. No, I do not.

Q. PLEASE EXPLAIN WHY NOT.

A. First, as the Companies have noted in other pleadings in this docket, the NOC Form utilized by Cherokee in its September 17, 2018 and December 12, 2018 communications to DEC/DEP was only applicable to small standard offer QFs of 2 MW or less. DEC and DEP each informed Cherokee of this deficiency by letters of October 5, 2018 and December 21, 2018, respectively, as further discussed by Witness Keen. In fact, upon review of the NOC Forms submitted by Cherokee, it is clear that Cherokee materially altered Section 3 of the NOC Form used by the Companies, to remove the requirement that the QF Seller must certify that it has a maximum nameplate capacity of 2 MW and is eligible for the Company's Standard Offer Tariff (which Cherokee was not). Additionally, Section 6 of the NOC Form states that the commitment terminates if the Seller (Cherokee) does not execute a PPA 30 days after the Company delivers an executable PPA to the Company. Applying this requirement, any purported LEO established by execution of the materially altered NOC Form would be terminated as a result of Cherokee's failure to execute the PPAs tendered by DEC and DEP.

Additionally, and as discussed by Witness Bowman, Cherokee's actions during the 2018-2020 time frame make clear that it did not commit its output to either DEC or DEP. Specifically, with regard to Cherokee's claimed LEO dates, neither of Cherokee's late 2018 communications represented a meaningful commitment to either DEC or DEP.

First, the letter to DEC cannot have represented a commitment to sell to DEC, because on December 12, 2018, Cherokee sent essentially the same letter to

DEP. Cherokee appears to have toggled back and forth between the Companies to see where it could get a better deal. This is similar to offering to sell my car to two different used car dealerships and not accepting the pricing that either dealership was willing to pay for the car. At no point would I be able to sell the same car to two different dealerships and obviously no legally enforceable commitment would be made until I committed to sell the car to one dealership and not the other at the price offered. Similarly, none of Cherokee's efforts indicate a commitment to sell to either DEC or DEP. Instead, Cherokee appears to be attempting to subvert the regulatory process by only offering pricing at a rate that works for itself, but that is unfair to the Companies and their customers.

Q. DO YOU HAVE ANY OTHER COMMENTS THAT SUPPORT WHY CHEROKEE'S ACTIONS DEMONSTRATE THAT NO LEO WAS ESTABLISHED?

A. Yes. It is important to recall that the ability of a QF to provide energy or capacity pursuant to a LEO involves the payment of rates for such purchases based on "the avoided costs" calculated either at the time of delivery or the time the obligation is incurred.[18] As detailed in Witness Keen's testimony, DEC and DEP each responded to Cherokee's communications by providing avoided cost rates calculated with current inputs and levelized fixed PPAs that were consistent with PPAs provided to other large QFs during that time frame. Each time, Cherokee rejected those rates and counter offered at rates that were well above the Companies' avoided costs. By rejecting each of the Companies' provided rates,

[18] 18 C.F.R. § 292.304(d)(1)(ii).

and making the inflated counter offers, Cherokee's claim of a LEO in each instance is not consistent with FERC's regulations and PURPA, which expressly limit the Companies' purchase obligations to rates set based on the utility's avoided cost. Simply put, Cherokee's continued rejection of avoided cost rate offers followed by counter offers to sell at above avoided cost rates indicates that it was not ready, willing and able to sell at the Companies' avoided costs.

Q. IS CHEROKEE'S CLAIM TO HAVE ESTABLISHED LEOs ON SEPTEMBER 17, 2018 AND DECEMBER 12, 2018 CONSISTENT WITH OTHER FERC GUIDANCE ON THIS SUBJECT?

A. No. As I note above, FERC recently emphasized the importance of LEOs for memorializing a commitment to sell to a utility so that the utility can rely on the QF's energy and capacity to reliably plan its system and serve its customers. Cherokee's actions are wholly inconsistent with this purpose of the LEO requirement. DEC cannot rely on Cherokee's energy and capacity to reliably plan its system and serve customers when Cherokee is—at the same time—offering that energy and capacity to DEP. Additionally, neither DEC nor DEP can rely on Cherokee to reliably plan and serve when Cherokee is rejecting rates calculated to reflect each utility's updated and actual avoided cost, and is counteroffering at rates far in excess of those avoided costs.

Q. HAS DUKE FOLLOWED ITS ESTABLISHED PROCESS FOR CALCULATING AVOIDED COST RATES FOR LARGE QFs IN RESPONDING TO CHEROKEE SINCE SEPTEMBER 2018?

A. Yes, the Companies followed their established process as I and the other DEC/DEP witnesses have described. However, it was Cherokee's responsibility to fully commit to sell its output to a single utility at that utility's avoided cost rate in order to establish a LEO, which it did not do.

IV. THE METHODOLOGY USED TO CALCULATE AVOIDED COSTS UNDER PURPA

(A) Overview

Q. WHAT METHODOLOGY DO THE COMPANIES USE TO CALCULATE AVOIDED COSTS?

A. DEC and DEP have consistently used the "peaker methodology" to forecast the Companies' avoided cost of capacity and energy in order to set the avoided cost rates paid to QFs. The Commission has consistently accepted the Companies' use of the peaker methodology to quantify DEC's and DEP's forecasted avoided capacity and energy costs. Specifically, in 2019, the Commission found that the peaker methodology is "a reasonable and appropriate methodology to fully and accurately quantify DEC's and DEP's forecasted capacity and energy cost to be avoided by purchases from QFs."[19]

Q. PLEASE DESCRIBE HOW THE COMPANIES USE THE PEAKER METHODOLOGY TO CALCULATE AVOIDED COST.

A. The peaker methodology is designed to determine a utility's marginal capacity and marginal energy cost, and therefore, can be applied to quantify a utility's avoided costs for purposes of pricing power purchases from QFs. This approach assumes

[19] Order No. 2019-881(A) at 29.

that when a utility's generating system is operating at equilibrium, the installed fixed capacity cost of a simple-cycle combustion turbine ("CT") generating unit (a "peaker") plus the variable marginal energy cost of running the system will produce a reasonable proxy for the marginal capacity and energy costs that a utility avoids by purchasing power from a QF. Consistent with PURPA, the peaker methodology is designed to ensure that purchases from new QF generators are not more expensive than the avoided capacity cost of a peaker plus the utility's forecasted avoided system marginal energy cost. Importantly, avoided costs are calculated based on the rules, regulations and market conditions in place at the time the rates are calculated.

Q. PLEASE DESCRIBE THE DIFFERENCE BETWEEN AVOIDED ENERGY COSTS AND AVOIDED CAPACITY COSTS UNDER THE PEAKER METHODOLOGY.

A. Avoided energy costs represent an estimate of the variable operating costs that are avoided and would have otherwise been incurred by the utility but for the purchase from a QF. Avoided energy costs, which are expressed in dollars per megawatt hour ("$/MWh"), include items such as avoided fuel, avoided variable environmental costs and avoided variable operations and maintenance ("VOM") costs. The peaker methodology approximates a utility's avoided energy cost through estimates produced by generation production cost modeling. Avoided capacity costs, on the other hand, represent fixed costs associated with the construction, financing and staffing of a CT facility. These fixed costs are not dependent on the actual use of the CT but rather the costs to build the CT and have it available to meet customer demand. As an analogy, if one was to purchase an electric vehicle, the avoided gasoline and avoided oil changes of a gas-powered vehicle would be the equivalent of avoided energy costs, which include avoided fuel costs and VOM. In addition, to the extent the electric vehicle offsets the purchase of a gas-powered vehicle, the car payment for the gas-powered vehicle would represent the fixed cost being avoided in the capacity payment and would be the equivalent of the avoided capacity cost.

Q. DO THE COMPANIES GENERALLY APPLY THE SAME METHODOLOGY FOR CALCULATING AVOIDED COST RATES TO LARGE QFs AS THEY DO FOR QFs THAT QUALIFY FOR THE STANDARD OFFER?

A. Yes. The Companies' established practice is to utilize the same peaker methodology in determining the avoided capacity and energy rates provided to both the Standard Offer as well as larger QFs not eligible for the Standard Offer. Pursuant to Order No. 2020-315(A), the Companies then update the inputs used in the peaker methodology for non-Standard Offer QFs on a quarterly basis to more accurately reflect the Companies' most current forecast of avoided costs.[20] However, as I noted above, DEC/DEP and large QFs are free to agree to other arrangements, including the dispatchable tolling arrangement that DEC provided to Cherokee last year, as discussed further by Witnesses Keen and Freund.

[20] These quarterly inputs are available publicly through the Companies' Large QF Tariff. Prior to Order No. 2020-315(A), these inputs were updated on a monthly basis and provided upon request from QFs (this process is described in greater detail earlier in my testimony).

(B) <u>Avoided Capacity Cost Calculation and Rate Design Methodology</u>

Q. IN GENERAL TERMS, HOW ARE AVOIDED CAPACITY COSTS CALCULATED UNDER THE PEAKER METHODOLOGY?

A. The peaker methodology credits avoided capacity value to the QF based on the value created from avoiding a marginal peaking resource. As I noted in the analogy of the QF as an electric vehicle, the avoided capacity cost is the annual car payment for the avoided gas-powered vehicle along with other fixed costs such as taxes. To arrive at an avoided capacity rate involves the following general steps.

1. The utilities' cost to construct a simple-cycle CT is calculated. These costs represent the fixed capital, financing and fixed operating costs associated with the construction and operation of a CT facility.
2. The fixed investment costs are converted to an annual cost that includes both the recovery-of and return-on the investment in the CT, along with the annual fixed operating costs, such as staffing.
3. The capacity values are increased by a Performance Adjustment Factor ("PAF") to put the QF on an equivalent basis to account for a certain level of forced outages on the utilities' systems. Line losses and other upward adjustments are also made in this step of the process to get to the annual capacity cost.
4. A determination of when capacity is first needed on each of the utilities' systems is made to ensure the capacity rate calculation includes value for capacity at the time when each system has an actual capacity need.
5. The annual value of capacity is allocated between peak winter and summer seasons based on when seasonal capacity is required for system reliability. At

this step, the avoided capacity value is expressed as a $/kW value for the winter season and a $/kW value for the summer season.

6. Finally, the winter and summer seasonal capacity values are then spread to the eligible capacity payment hours. The resulting avoided capacity rates are expressed in cents per kilowatt-hour ("cents/kWh"), as shown in the Companies' applicable tariffs.

Q. HOW DOES THE TIMING OF THE UTILITIES' NEED FOR INCREMENTAL GENERATING CAPACITY IMPACT THE CALCULATION OF THE AVOIDED CAPACITY PAYMENT?

A. As discussed by Witness Bowman, a central tenet of PURPA provides that customers should not be required to pay QFs for avoided capacity unless the QF is actually offsetting a capacity need of the utility. PURPA's clear intent is to estimate the costs that, but for purchase from the QF, would have otherwise been incurred by the utility and its customers. Accordingly, the annual fixed capacity costs used in the avoided cost rate calculation include the annual fixed capacity costs starting with the first year in which an actual avoidable capacity need exists, as determined by the Companies' respective IRPs.

Prior to the year in which the next avoidable generation unit is needed, the utility does not have a capacity need to avoid, and therefore in the calculation of the capacity rate, no value for avoided capacity is ascribed in these years. If this was not accounted for, customers would be paying a QF for marginal capacity that is providing no actual benefit to serve their needs for capacity.

Q. YOU STATE THAT THE PROJECTED CAPACITY NEED MUST BE AVOIDABLE IN ORDER TO BE REFLECTED IN RATES. WHY MUST THE NEED BE AVOIDABLE?

A. The capacity need must be actually avoidable because otherwise the capacity rate would not meet the FERC requirement that avoided cost rates be calculated to reflect the cost that the utility would pay for capacity "but for" the QF. For example, near-term designated capacity additions, such as scheduled uprates at existing units, are not recognized as avoidable capacity. Such uprates are usually accomplished in the normal course of business during regular maintenance cycles where additional efficiencies and/or technology gains are realized. In contrast, as I explain later in my testimony, new, undesignated capacity additions, such as future planned battery storage or gas CTs that are not already committed or "designated," may be avoidable by a QF purchase.

Q. IF A UTILITY'S NEXT AVOIDED CAPACITY NEED IS SEVERAL YEARS IN THE FUTURE, WHEN DOES THE QF BEGIN RECEIVING A CAPACITY PAYMENT?

A. Under the levelized rate design, the avoided capacity payments are levelized to allow the QF to receive an avoided capacity payment in each year of the contract, as long as an actual capacity need exists at some point within the term of the avoided cost contract period. More precisely, the QF will receive a levelized capacity rate that takes into account a zero value of capacity in the initial years prior to the utility's first avoidable capacity need, as well as an avoidable capacity value in all subsequent years of the avoided cost period. Put another way, the QF will receive capacity payments during each year of the contract, in order to credit the QF for the future avoided capacity, so long as the utility has an avoidable capacity need within the avoided cost contract period.

Q. IS RECOGNITION OF DEC'S AND DEP'S NEED FOR CAPACITY IN THIS CALCULATION FAIR TO THE COMPANIES' CUSTOMERS AND TO QFs?

A. Yes. The Companies' customers only pay capacity payments to the QF that are equal to the economic value of the utility's actual avoided capacity cost. This approach is also fair and non-discriminatory to QFs.

Q. HAS THE COMMISSION APPROVED THIS APPROACH?

A. Yes, it has. The Companies adhered to this first year of need principle based on the 2019 IRPs in developing the avoided cost rates that were filed in the 2019 Avoided Cost Proceeding and approved by the Commission in Order No. 2019-881(A).[21] Notably, no intervenors challenged this methodological approach to quantifying avoidable capacity costs in the 2019 Avoided Cost Proceeding in the same way that Cherokee has done here to suggest that it should be paid more for capacity before DEC's first year of avoidable capacity need.

Q. HAS FERC OR NORTH CAROLINA ALSO APPROVED THIS APPROACH?

A. Yes, both have. The NCUC approved this approach in its final order in Docket No.

[21] Order No. 2019-881(A) at 89-92.

E-100, Sub 148.[22] As discussed by Witness Bowman, FERC most recently supported this approach in Order No. 872 where it clarified that when a purchasing utility does not avoid the construction or purchase of capacity due to entering into a contract with a QF, the only costs avoided by the utility would be the incremental costs of purchasing or producing energy.[23]

Q. IN WHAT YEARS DID THE COMPANIES' INTEGRATED RESOURCE PLANS IDENTIFY THE FIRST AVOIDABLE CAPACITY NEED AT THE TIME WHEN CHEROKEE INITIALLY CLAIMS IT ESTABLISHED LEOs WITH DEC AND DEP?

A. At the time that Cherokee submitted its September 17, 2018 communication to DEC, DEC's first avoidable capacity need as identified in its 2018 IRP was projected to arise in 2028.[24]

At the time that Cherokee submitted its December 12, 2018 communication to DEP, DEP's first avoidable capacity need as identified in its 2018 IRP was projected to arise in 2020.[25] Notably, DEP had a near term need for capacity during the 2020-2024 timeframe and, to meet that projected need, procured capacity and energy through a non-PURPA competitive market solicitation in October 2018. As

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[22] *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016*, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 48, Docket No. E-100, Sub 148 (Oct. 11, 2017).

[23] Order No. 872 at P 347; *see also City of Ketchikan, Alaska,* 94 FERC ¶ 61,293 (2001).

[24] *See* Duke Energy Carolinas, LLC 2018 Integrated Resource Plan at 55, Docket No. 2018-10-E (filed Aug. 31, 2018) ("DEC 2018 IRP").

[25] *See* Duke Energy Progress, LLC 2018 Integrated Resource Plan at 55, Docket No. 2018-8-E (filed Nov. 1, 2018) ("DEP 2018 IRP").

discuss by Witness Keen, Cherokee participated in that solicitation but was not successful as its price was in excess of that of the winning bidders.

Q. CAN YOU SUMMARIZE THE COMPANIES' RESPECTIVE FIRST AVOIDABLE CAPACITY NEED AT EACH POINT IN TIME WHEN CHEROKEE CLAIMS IT ESTABLISHED LEOs AND DEC/DEP PROVIDED AVOIDED COST RATES?

A. Yes. My Figure 1 below summarizes DEC's and DEP's projected first avoidable capacity needs used in developing the rates provided to Cherokee for each of five different times DEC and DEP provided avoided cost rates to Cherokee:

Snider Direct Figure 1:

First Avoidable Capacity Need Relevant to Cherokee Rates

Cherokee request date	Date of DEC/DEP providing rates	DEC/DEP	Most up to date year of avoidable capacity need
9/17/18	10/31/18	DEC	2028
12/12/18	2/1/19	DEP	2020
5/4/20	6/24/20	DEP	2020
9/17/20	9/17/20	DEC	2026
N/A	2/10/21	DEC	2026

Q. WITNESS STRUNK STATES THAT IN ITS 2018 IRP, DEC "IDENTIFIES INVESTMENTS IN NEW CAPACITY ADDITIONS DURING THE PERIOD 2020-2024. A NEW OR RENEWED PURPA CONTRACT WITH THE CHEROKEE FACILITY PROVIDED DEC WITH AN OPPORTUNITY TO DEFER OR AVOID SUCH INVESTMENTS. IN SUCH A CONTEXT, IT WAS UNREASONABLE FOR DEC TO POSTURE THAT IT 'DOES NOT HAVE A CAPACITY NEED' IN ITS 2018 NEGOTIATIONS

WITH CHEROKEE FOR A PURPA CONTRACT BEGINNING JANUARY 1, 2021."[26] DO YOU AGREE?

A. I do not. Witness Strunk follows this contention by pointing to "two sets of designated capacity additions in the relevant time frame:" upgrades to the Bad Creek Pumped Hydro Station and the 402 MW Lincoln County combustion turbine ("Lincoln CT"). He also mentions other projected capacity additions identified in the DEC 2018 IRP. While he does not explicitly say so, it appears that Witness Strunk is contending that the identification of these capacity additions in the DEC 2018 IRP contradicts DEC's position that it did not have an avoidable capacity need that could be met by Cherokee and support avoided capacity cost rates in 2018/2019. That contention would be incorrect.

Q. WHY DO THESE IDENTIFIED CAPACITY ADDITIONS NOT SHOW THAT DEC HAD AN AVOIDABLE CAPACITY NEED THAT CHEROKEE COULD HELP TO MEET?

A. The Companies' methodology to determine each utility's future (avoidable) generation need is based on the difference between customer demand, net of energy efficiency, and the sum of the utility's existing resources and designated resources, to meet a required annual planning reserve margin (currently 17% for both DEC and DEP). When this difference causes the annual planning reserve margin to fall below 17%, a new resource is required in order to reliably meet customer needs.[27] DEC's and DEP's respective IRP models select the most economic resources to

[26] Strunk Direct at 11-12.

[27] DEC and DEP's first year of need is identified in Table 12-D in each of the Companies' 2018 IRPs. *See* DEC 2018 IRP at 55; DEC 2018 IRP at 55.

meet customers' need in the first year that a new capacity resource is required to maintain the planning reserve margin.

Q. CAN YOU EXPLAIN THE PROCESS THE COMPANIES USE TO IDENTIFY WHEN AN AVOIDABLE CAPACITY NEED ARISES IN MORE DETAIL?

A. Yes. The resources used to meet the future load requirements fall into two categories: designated and undesignated. Designated resources include existing resources that are currently in service as well as future projects already underway such as those that have been granted a Certificate of Public Convenience and Necessity ("CPCN") or Certificate of Environmental Compatibility and Public Convenience and Necessity ("CECPCN"), smaller capacity additions that are a result of unit uprates that are in the Companies' planning budget, firm market purchases over the duration of their signed contract, and demand side management ("DSM")/energy efficiency ("EE") programs. In contrast, undesignated resources, which may be avoided or deferred by the QF, include potential purchase power contracts that have not yet been executed, future battery storage projects not yet committed to, and projected natural gas resources in the IRP that have not been granted a CECPCN in South Carolina or a CPCN in North Carolina.

In summary, the first avoidable need is determined by considering only designated resources in the plan while excluding all undesignated future resources, which are assumed to be avoidable. An avoidable capacity need arises when designated resources are insufficient to provide a 17% reserve margin over the planning horizon.

Q. DO YOU AGREE WITH WITNESS STRUNK'S SUGGESTION THAT CHEROKEE COULD AVOID THE 402 MW LINCOLN CT PLANNED TO BE PLACED INTO SERVICE IN 2024?

A. No. The Lincoln CT received a CPCN from the NCUC in 2017, which was prior to the time Cherokee asked for avoided cost rates, and, therefore, was "approved for construction" and not avoidable in the fall of 2018.[28] As described above the Lincoln CT was therefore a "designated" resource in 2018 and did not represent an avoidable capacity resource in the DEC resource plan.

Q. WHAT ABOUT THE UPGRADES TO THE BAD CREEK PUMPED STORAGE FACILITY AND OTHER PLANNED NEAR-TERM CAPACITY IDENTIFIED BY WITNESS STRUNK?

A. With regard to the Bad Creek uprates, these capacity additions exemplify a situation where uprates are conducted in the normal course of business, as part of major maintenance schedules. Such maintenance-related "uprate" capacity additions cannot be avoided by a new QF once the projects are funded and under way. As such, they are also not undesignated or avoidable. In addition, the Bad Creek uprates were identified by DEC as far back as its 2016 IRP, long before the negotiations for the Cherokee PPA commenced in late 2018.

[28] *In the Matter of Application of Duke Energy Carolinas, LLC, for a Certificate of Public Convenience and Necessity to Construct a 402-MW Natural Gas-Fired Combustion Turbine Generating Facility in Lincoln County, North Carolina*, Order Issuing Certificate of Public Convenience and Necessity with Conditions, Docket No. E-7, Sub 1134 (Dec. 7, 2017).

As noted above, the Companies do not consider undesignated capacity when determining their first year of avoidable capacity need. Only existing and designated future resources are considered in the determination of the first year of avoidable need. Witness Strunk identifies in his testimony both designated resources such as the Lincoln CT and undesignated resources such as potential future energy storage resources that are shown in the DEC IRP. Witness Strunk's testimony therefore fails to recognize that only existing and designated resources are considered in the Companies' determination of when the first year an avoidable need arises.

Q. HAS THIS COMMISSION OR THE NCUC RECOGNIZED THAT THESE PROJECTS WERE NOT AVOIDABLE IN LATE 2018?

A. Yes, both this Commission and the NCUC recognized in their most recent avoided cost orders that these projects were not avoidable. In Order No. 2019-881(A), the Commission found that DEC appropriately identified its first year of need as 2026 as presented in its 2019 IRP.[29] In its final order in its 2018 avoided cost proceeding, the NCUC also concluded that DEC appropriately identified its first avoidable capacity need (2028) as appropriately presented in its 2018 IRP.[30]

Q. HOW DO YOU RESPOND TO WITNESS STRUNK'S ALLEGATIONS OF DISCRIMINATORY TREATMENT THAT AT THE TIME WHEN DEC OFFERED CHEROKEE A 5-YEAR RATE EXCLUDING CAPACITY, DEC

[29] Order No. 2019-881(A) at 82-83.

[30] Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 46, Docket No. E-100, Sub 158 (Apr. 15, 2020).

WAS AT THE SAME TIME PROVIDING OTHER QFs A RATE THAT INCLUDED CAPACITY?

A. Witness Strunk points to DEC's standard offer rate available to QFs under Schedule PP, which he states provides compensation for both avoided energy and capacity, and claims that DEC's "decision" not to provide avoided capacity cost to Cherokee was discriminatory.[31] As Witness Strunk himself points out, the Schedule PP available in September 2018 was available to only QFs eligible for the standard rate schedule,[32] which is limited to QFs 2 MW or less. Cherokee is a very large cogenerator QF that is not eligible for the 2 MW and under standard rate schedule. DEC therefore applied the same process and methodology that it uses for all large QFs to calculate the rates for Cherokee, which I discuss above. Large QFs' rates are calculated at the time the LEO is incurred, which while under dispute in this case is certainly not before September 2018, and at that time DEC did not have a capacity need until 2028.

Q. PLEASE SUMMARIZE YOUR TESTIMONY ON THE APPROPRIATENESS OF THE AVOIDED CAPACITY RATES THAT THE COMPANIES PROVIDED TO CHEROKEE.

A. The Companies calculated the avoided capacity cost rates provided to Cherokee consistently with how they calculate avoided capacity for other large QFs and consistently with FERC and Commission requirements, by only providing capacity rates based on each utility's first projected avoidable capacity need as shown in the

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[31] Strunk Direct at 12-13.

[32] *Id.* at 10.

most recent IRP, and by updating the inputs to the rates each time they were developed.

(C) Avoided Energy Cost Calculation and Rate Design Methodology

Q. IN GENERAL TERMS, HOW ARE AVOIDED ENERGY COSTS CALCULATED UNDER THE PEAKER METHODOLOGY?

A. In any given hour, a utility will have a variety of units online such as hydro-electric, nuclear, solar, natural gas combined-cycle, coal, natural gas simple-cycle CTs and diesel fuel oil CT resources. These units all have differing variable fuel and operating costs that are considered in order to dispatch them in economic merit order to meet the utility's instantaneous load obligations. To calculate the avoided marginal energy value, two production cost simulations are performed and then compared to each other to determine the value of QF energy. A production cost model simulates the generation commitment and dispatch of the utility's fleet of generating resources needed to meet the utility's load over the avoided cost period on an hour-to-hour basis. The first simulation uses IRP models and current market assumptions to establish the "base case" of the estimated variable production costs over the period. The second simulation is identical to the first but adds a hypothetical 100 MW of no-cost generation to the utility's generating fleet, which is available to the system in every hour of the avoided cost period. Adding this hypothetical, no-cost generation to the simulation displaces energy from the marginal units that were operating in the "base case," and as a result, lowers the overall variable production costs relative to the base case. Comparing the hourly production cost associated with the base case relative to the second case with the

100 MW of no-cost generation determines the marginal hourly energy costs that can be avoided over the study period. These marginal avoided costs are then used to calculate the avoided energy rates that leave a customer indifferent between QF purchases and generation provided by the utility.

Q. WHAT FACTORS INFLUENCE THE CALCULATION OF THE AVOIDED ENERGY COST RATES?

A. A number of factors drive the avoided cost calculation change over time, including load and energy forecasts, resource mix, unit characteristics, VOM costs, environmental emissions costs, reagent costs and fuel costs. While updating items such as VOM costs, environmental reagent costs, and the relative efficiency of the marginal unit with the most current information all factor into the utility's marginal cost of generation, changes in the commodity market price for natural gas also represent a significant change impacting the Companies' avoided costs. This is because natural gas commodity prices represent a key driver of the avoidable energy cost since a natural gas-fueled combined-cycle unit or combustion turbine unit is often the marginal resource.

Q. DID THE RATES PROVIDED TO CHEROKEE APPROPRIATELY IMPLEMENT THIS METHODOLOGY FOR CALCULATING AVOIDED ENERGY COST RATES?

A. Based on my review of the pleadings, yes. Witness John Freund also discusses the Companies' specific application of this methodology to Cherokee in his testimony.

V. <u>DECLINE IN AVOIDED COSTS SINCE 2012</u>

Q. CHEROKEE COMPLAINS THAT THE AVOIDED COST RATES PROVIDED BY DEC IN 2018, DEP IN 2019, AND DEC AGAIN IN 2020 ARE LOWER THAN THE RATES PROVIDED IN THE 2012 PPA. IS IT ACCURATE TO SAY THAT THE COMPANIES' AVOIDED COST RATES HAVE DECLINED OVER THIS TIME FRAME?

A. Yes. The rates have declined significantly since 2012, as shown in my Figure 2 below.

Snider Direct Figure 2:[33]

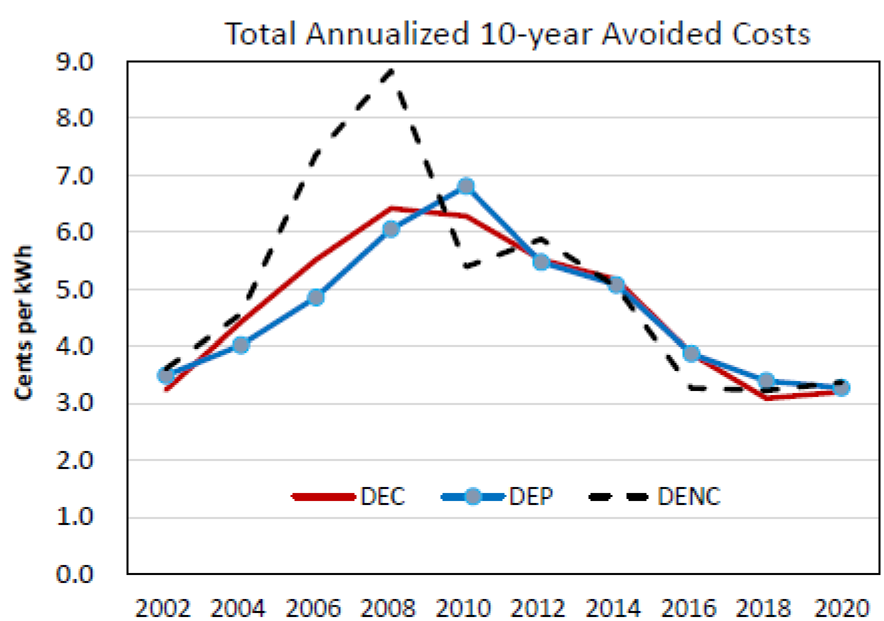

Figure 1: Total Annualized 10-year Avoided Costs (Approved and Proposed)

[33] Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2020, Initial Statement of the Public Staff – North Carolina Utilities Commission at 8, Docket No. E-100, Sub 167 (Jan. 25, 2021) (showing approved total avoided costs for DEC, DEP, and Dominion Energy North Carolina from 2002-2018 and proposed annualized avoided cost rates for 2020).

Q. CAN YOU COMMENT ON WHY AVOIDED COST RATES HAVE DECLINED SO SIGNIFICANTLY SINCE THE 2012 TIME FRAME WHEN CHEROKEE'S CURRENT CONTRACT TERM COMMENCED?

A. Yes. The decline in rates reflects a decline in avoided costs, which is due to several factors. First, natural gas and other commodity costs, which are an important input in calculating avoided energy cost rates, have declined significantly during this time frame. Second, both Companies' capacity needs have declined over this time frame, due to construction of new efficient capacity and procuring new capacity from third party-owned generation including the addition of approximately 4,000 MW of QF solar between DEC and DEP.

Q. DOES THE FACT THAT THE AVOIDED COST RATES PROVIDED TO CHEROKEE BY THE COMPANIES DURING 2018-2020 ARE LOWER THAN THE RATES CHEROKEE RECEIVED IN 2012 MEAN THAT THE RATES PROVIDED DURING 2018-2020 WERE INACCURATE OR INAPPROPRIATE?

A. No. The lower level of avoided cost rates provided by DEC and DEP to Cherokee during this time frame simply reflects systemic declines in gas prices and the reduced capacity needs on the Companies' system as compared to the 2012 time frame. The lower rates are accurate and appropriately calculate avoided cost rates to reflect current inputs, and these rates therefore represent each of the Companies' actual avoided costs at the time they were calculated, consistent with the requirements of PURPA, FERC's regulations, and Act 62.

VI. TRANSPARENCY OF AVOIDED COSTS

Q. ARE THERE ANY ADDITIONAL OBLIGATIONS WITH WHICH DEC AND DEP MUST COMPLY WHEN PROVIDING AVOIDED COST RATES TO QFs THAT YOU WOULD LIKE TO MENTION?

A. Yes. Act 62 requires that each electric utility's avoided cost filings must be "reasonably transparent" so that "underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission."[34] In addition, FERC's regulations require electric utilities to make forecasted avoided capacity and energy information available to QFs.[35]

Q. HAS THIS COMMISSION SPOKEN TO TRANSPARENCY OF AVOIDED COST RATES IN ITS RECENT ORDERS?

A. Yes. In Order No. 2020-315(A), the Commission directed the Companies to file the Standard Large QF PPA using a "flat" technology-neutral 100 MW production profile rather than a project-specific profile, and to calculate energy and capacity rates for large QFs using updated inputs such as fuel prices and an updated resource plan. The Commission also stated that "[i]n the interest of transparency Duke shall be required to provide detailed information regarding those updated inputs on request to QFs that are negotiating a [PPA] with Duke."[36]

[34] S.C. Code. Ann. § 58-41-20(J).
[35] 18 C.F.R. § 292.302(b).

[36] Order No. 2020-315(A) at 23.

Q. IN YOUR OPINION, HAVE THE COMPANIES COMPLIED WITH THEIR OBLIGATIONS WITH REGARD TO TRANSPARENCY IN THEIR NEGOTIATIONS WITH CHEROKEE?

A. Yes. Witnesses Keen and Freund address this further in their testimony, but based on my review of their testimony and the pleadings in this case, the Companies were reasonably transparent with regard to information related to the avoided cost rates provided to Cherokee as required by Act 62 and the Commission.

VII. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.